STAFF BACKGROUND PAPER ON LOAD RESEARCH DATA REQUIREMENTS AT THE CALIFORNIA ENERGY COMMISSION

The Ad Hoc Information Committee

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I. Background

The California Energy Commission (Energy Commission) is currently examining its data collection and submission requirements as one phase of an Order Initiating Rulemaking (OIR). Existing regulations require utilities to acquire system data and to submit those data to the Energy Commission to support monitoring and policy assessment functions. Previous staff papers have provided an overview of consumer data needs for monitoring and policy assessment,[1] while other papers specifically addressed survey techniques and needs for energy consumption data.[2] This paper focuses on the load research component of system data. Staff describes the data currently being collected, Energy Commission needs for load research data, and options for the collection of such data. It is hoped that this paper will facilitate further discussion of system data needs.

II. What Are Load Research Data?

Load research data are data on patterns of customer energy consumption and demand based on specified time periods, usually hourly or half-hourly. Load research data is collected at three different levels: system, customer, and end-use. System load data are collected at points along the transmission system and account for the hourly loads in a utility's service/planning area. Customer load data is collected through recorders installed on the revenue meters of a sample of customers. End-use load data, such as air conditioning load, is collected through recorders installed on individual appliances or on dedicated circuits of a sample of customers. A hourly or half-hourly series of such data comprises a load profile for the system, customer or end-use. An example of load research data is the customer- and hourly usage information collected by the utility distribution companies (UDCs) for use in preparation of dynamic load profiles to be used for eligible direct access customers in lieu of interval metering.

III. Current Load Research Data Requirements

This section describes the type of load data currently being provided to the Energy Commission and how the data are used. Included in this section are anticipated future uses of the data and why its collection is important to the Energy Commission's monitoring and policy assessment functions.

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1 Jaske, Michael R., "Consumer Information Needs To Support Monitoring and Policy Assessment Functions", September 4, 1998.

2 Lang, Judy: "Basic Steps In Conducting Surveys" and "Collecting Consumer Structural Characteristics Data By Means Of Surveys"; Lang, J., Rohrer, Richard and Gough, Andrea: "Self-Generation Reporting / Estimation Alternatives"; Cullen, Gary and Rohrer, R.: "Universal Collection and Submission of Consumer Information; all September 15, 1998.

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A. Data Currently Provided to the Energy Commission

Large electric utilities are currently required to provide load research information to the Energy Commission in accordance with Title 20, California Code of Regulations, Section 1344.[3] These regulations require large utilities to conduct specified load metering projects and to submit information from their efforts to the Energy Commission on an annual basis. The projects include: 1) annual system load data by hour, 2) estimates of peak load daily load profiles by customer sector, and 3) air conditioning load profiles for the residential and commercial building sectors. Table 1 displays a matrix of the data required to be reported by utilities in accordance with Title 20, Section 1344.

TABLE 1
LOAD RESEARCH DATA REQUIREMENTS

Utility Type	Hourly System Load Data	Coincident Peak Load By Sector	Monthly Load Characteristics	End-Use Load Characteristics
Investor Owned	Hourly system load data for a calendar year. Data required to be delivered annually in EEI format.	Estimates of Sector Coincident peak. Sectors include residential, commercial, industrial, ag. & pumping, street lighting & other, and resale cities. Data required to be delivered annual, one coincident peak value for each sector.	Typical weekday and weekend load profile and peak day load profiles for each calendar month. Data required to be delivered annually.	Air conditioning load profiles containing contribution to system peak for typical weekday, weekend, and peak day for each calendar month. Data required to be delivered annually.
SMUD and LADWP	Hourly system load data for a calendar year. Data required to be delivered annually in EEI format.	Estimates of Sector Coincident peak. Sectors include residential, commercial, industrial, ag. & pumping, street lighting & other, and resale cities. Data required to be delivered annual, one coincident peak value for each sector.	Typical weekday and weekend load profile and peak day load profiles for each calendar month. Data required to be delivered annually.	Air conditioning load profiles containing contribution to system peak for typical weekday, weekend, and peak day for each calendar month. In the annual data plans process the Energy Commission has exceeded these requirements.
Small & Medium Utilities	Hourly system load data for a calendar year. Data voluntarily delivered annually.	NA	NA	NA

[3] Large-sized electric utilities are defined in the regulations to be any electric utility which has experienced a peak electricity demand of 1000 megawatts or more in the two calendar years preceding the filing date of the data collection and analysis plan. Medium-sized electric utilities have experienced peak electricity demand of more than 200 megawatts but less than 1000 megawatts in the two calendar years, and small electric utilities have had demands of 200 megawatts or less.

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Small-sized electric utilities are not required to submit hourly system load information to the Energy Commission. Medium-sized utilities can satisfy Energy Commission data requirements either through customer surveys or load research. Some medium-sized utilities have chosen to do load research since the Federal Energy Regulatory Commission (FERC) requires the data if a utility has a system peak greater than 200 megawatts (MW) and has the obligation to secure resources to service that demand.[4] Although there is a small amount of natural gas load research conducted by California utilities, the Energy Commission has no requirements for such data.

The system load data submittal describes the utility's system load for every hour of the previous calendar year. The regulations require the system load profile to be based on actual load metering. The regulations call for the delivery of the data in Edison Electric Institute (EEI) format, but Energy Commission staff has accepted profiles in other formats provided the formats were accurately described. This has particularly facilitated the delivery of annual system hourly load from medium-sized utilities.

The peak load reports by customer sector provide estimates of sector loads coincident with the system peak for the previous calendar year. Sectors to be specified include the residential, commercial building, other commercial, industrial, agricultural and water pumping, and resale sectors. These sectors are defined using a mapping of SIC codes to economic customers groups.[5] The regulations require that samples used to estimate peak loads for each sector be designed to ensure that estimates are accurate to within + 10% of the sector load coincident with system peak, with 90% confidence.

The daily load profile reports, by customer sector, contains monthly load characteristics by the aforementioned sectors. The required profiles are the contributions of each sector to the system hourly load for a typical weekday, a typical weekend day, and the system peak day for each month of the previous calendar year. Samples used to develop each monthly sector load profile shall be designed to ensure that such profiles are accurate to within + 10% of the monthly sector peak with 90% confidence.

Reports submitted for air conditioning load profiles in the residential and commercial building sectors should contain the contribution of residential and commercial building air conditioning to the system load for a typical weekday, a typical weekend day, and the monthly peak day for each summer month of the year. The residential sample should be designed to be accurate to within ±10% with 90% confidence while the commercial building sector sample should have a minimum of 200 commercial building units.

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4 Phone conversation with Meesha Bond at FERC, October 22, 1998.

5 Preparation of load patterns by economic sector effectively requires utilities to have SIC codes for the load research samples and knowledge of SIC-based characteristics for the entire customer population.

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B. How the Data Are Used

There are many industry monitoring activities where descriptive data about hourly load is important. A primary use for the data supplied in the required reports are used to calibrate the Hourly Electric Load Model (HELM)[6], which staff has used to prepare long-run peak demand forecasts. Within HELM are highly disaggregated load profiles that distribute annual energy consumption for individual end-uses or other disaggregated categories throughout the 8,760 hours of a year. The typical weekday and weekend load profiles by month are used as a check against the modeled load profiles in HELM. These profiles will be used even more extensively in the future as staff changes from forecasting planning coincident peak load for the year to forecasting 8,760 hourly loads by geographic region. During calibration each sector's modeled coincident peak load is calibrated to its estimated peak load as reported by the utilities in the annual reports. Then the system load data is used to calibrate HELM's estimated system peak. The difference between the actual system peak and HELM's coincident peak is allocated to each sector's modeled peak load based on its historic contribution to the system peak as estimated from the load research data.

Hourly load forecasts are primary inputs into electric system simulation models, such as ELFIN, UPLAN, and others that estimate generating system operating results (e.g., system prices, fuel use, reliability, etc.) In the past the hourly load forecasts have been produced using engineering estimates of disaggregate load shapes, calibrated to sector coincident peaks. As the hourly energy market becomes more transparent, collecting actual load patterns will enhance the results of demand models that forecast consumption and system models that forecast prices, fuel use, and reliability.

C. Anticipated Future Needs

1. Forecasts

As part of the Energy Commission's strategic plan an annual Baseline Energy Outlook will be produced to provide a source document for current and project electricity consumption patterns. The 1998 Baseline Energy Outlook was placed on the Energy Commission's website in August, 1998, and has since been downloaded more that 1,250 times. Some examples of the 1998 Baseline Energy Outlook being used as a source document includes:

- PG&E's use of the forecasts in its current GRC;
- the Independent System Operator (ISO) use of the forecasts in its statutorily mandated PUC section 350 study of reliability and use as a comparative source document for its 1999 load forecast;

6 HELM was developed by Electric Power Research Institute to produce end-use hourly load estimates.

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- Sierra Energy Risk and Assessment, Inc. and Environmental Science Associates use of the forecasts in valuation of PG&E's fossil-fuel generation plant divestiture; and,
- the many general data requests staff receives from the public on consumption patterns by building types, end-use and location.

Three key observations can be made about energy forecasts in the newly restructured energy marketplace. First, short-term forecasts used for load scheduling and load bidding will become much more important as a result of the financial commitments made by industry participants as they schedule power with the ISO and make bids into the Power Exchange (PX). The large financial commitments associated with scheduling and bidding will force participants to develop their own short-term forecasting expertise (e.g., day-ahead and hour-ahead). Second, intermediate term forecasts (i.e., two-to-five years) will continue to be important to generation facility operators/constructors hoping to sell power to consumers in competitive market environment in which the power plant owner accepts the risk of misunderstanding the size of the market and long term viability of specific power plants. Third, three-to-ten year forecasts used in policy evaluations will become even more important as volatility permitted by a competitive industry structure results in changes on an unprecedented scale and pace compared to the traditional industry structure. Long term system reliability and transmission system expansion are applications that require longer term forecasts.

The forecasts in the Baseline Energy Outlook respond directly to the latter two observations by providing the most current outlook for statewide energy consumption patterns. Simple aggregation of various forecasts prepared by industry participates for their own activity will result in an overestimation of energy consumption and peak demand as each market participant optimistically projects greater market shares. Staff's forecasts, however, are built upon economic and demographic data for the state and its regions, thus avoiding the inherent problem of growing market shares. These forecast also have the advantage of a common forecasting methodology that ensures a uniform translation of economic/demographic and other important influences on the demand for electricity and other energy forms.

To better reflect the information needs of the restructured electricity marketplace the Baseline Outlook must incorporate two new realities. First, the importance of knowing where consumption occurs (e.g., either at the county or ISO transmission congestion zone level) will be at a less aggregated level than the existing utility planning areas. Consumption patterns for each hour of the year will become as important as a point estimate of annual coincident system peak demand as a result of the newly created competitive electric generation market denominated in hourly time intervals. In order to address these two new realities load research data will be needed. And the manner in which the data is reported and analyzed will need to change.

2. Energy Efficiency Market Transformation; Building & Appliance Standards; and Research, Development & Deployment

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The establishment of sound policy for energy efficiency market transformation, building and appliance standards, and fiduciary use of public research, development and deployment expenditures will become much more dependent on load research data. In the past benefits/costs analysis for building and appliance standards were based on estimates of the annual value of kWh saved. In the restructured electricity marketplace the benefits stemming from building and appliance standards, energy efficiency market transformation, and RD&D will not only depend how many kWh are saved, but more importantly when those kWh are saved. Load research data will be needed to estimate the kWh saved in the appropriate hours because of the strong variations in market price for electricity over the hours of the day and months of the year.

IV. CPUC Data Requirements

The Energy Commission is not alone in requiring utilities to report results from load research data. In this section staff summarizes our understanding of the reporting requirements at the California Public Utilities Commission (CPUC).[7]

A. General Rate Case Proceedings

The CPUC has required the utilities to make use of load research data in General Rate Case (GRC) proceedings. In the past the utilities have used load research results in Phase II of the GRC to estimate each rate group's contribution to peak demand. The coincident peak estimates were then used to allocate generation, transmission and distribution capacity costs on an equal percent marginal cost (EPMC) basis. The utilities were also required to provide compiled load research results, in spreadsheet format, to the Office of Ratepayers Advocate (ORA) so that ORA staff could perform their own analysis of EMPC allocations. ORA could also request the detailed load research data itself for a more in-depth assessment of specific issues.

Future GRCs will be reduced in scope and frequency due to electricity restructuring and reliance upon performance base ratemaking (PBR) as an alternative regulatory oversight process. Development of a marketplace for electricity generation eliminates the need to use load research for EMPC allocation of generation capacity. ORA staff believe, however, that load research data will still be required to allocate transmission and distribution capacity costs on a EMPC basis during Phase II of GRCs for transmission and distribution.

B. Load Profiling

As part of implementing electricity restructuring the CPUC created two new uses for load profiles derived from utility load research data. Here, a load profile is defined as a statistical representation of the average customer's hourly load in a particular customer class over a defined

[7] Energy Commission staff attempted to schedule an informal meeting with the investor-owned utilities to fully understand other agency reporting requirements, but the utilities were unable to participate in the timeframe needed to prepare this background paper.

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period of time. The load profile can then be used to distribute a cumulative meter read or reads over all the hours in a time period. In decision D.97-05-040, the CPUC authorized the use of load profiles as a means of allowing smaller customers (i.e., residential and commercial customers with maximum demand of less than 50 kilowatts (kW)) the option to participate in direct access without purchasing an hourly interval meter. In decision D.97-08-056 the CPUC dictated that load profiles be used to calculated the average PX costs/credits and residual competitive transition charges (CTC) by customer class.

These two new uses of load research data require the utilities to maintain their load research samples until March 31, 2002, or expiration of the CTC, and quite possibly beyond. To the extent that UDCs provide default service and customers are not required to install interval metering, then something akin to a load profile will be needed to weight hourly PX prices and compute an average kWh charge. Moreover, the utilities may be required by the CPUC to expand their load research samples depending upon resolution of issues surrounding segmentation of the load profile classes. The CPUC has also stated its intention to review the use of load profiles as a means of allowing direct access participation by smaller customers in the year 2000. Depending upon factors such as the cost of hourly interval meters, small customer participation, and effectiveness of load profiling, the CPUC could rule the continued use of load profiles for smaller customers.

Table 2 on the following page displays the load profile groups used by the UDCs to calculate the average PX costs/credits and CTCs. Each profile is a statistical representation of a group of customers by rate class for which the UDCs have load research samples in place. As indicated in the table there is a great deal of information being made available. Unfortunately, the table also shows that these load profiles do not correspond directly to the economic-activity-defined customers sectors required by Title 20, Section 1344 (i.e., residential, commercial building, other commercial, industrial, agricultural and water pumping, and resale sectors).

C. Future Rate Design

In its rate unbundling proceeding, the CPUC has called upon the utilities to propose post-rate freeze designs by January 15, 1999. Unless the utilities proposed substantial changes, which according ORA staff is unlikely,[8] the use of load research data for EMPC allocations can be expected to be part of post-rate freeze ratemaking for transmission and distribution components.

V. Data Requirements Of Other Entities

In this section staff inquires about the reporting requirements of the Federal Energy Regulatory Commission (FERC) and other entities. Due to limited Staff knowledge of these reporting

8 Telephone discussion with Marshall Enderby on October 21, 1998.

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requirements we hope that the utilities or other knowledgeable parties will supplement the record of this proceeding beyond the following brief descriptions on this issue. Of specific concern is whether or not the utilities will continue to be required to submit hourly system load to FERC.

A. FERC Requirements

FERC requires utilities to report hourly load data as part of Form 714 report entitled "Annual Electric Control and Planning Area Report". Responding utilities are those that have annual peak demand greater than 200 MW, are responsible for forecasting system demand, and have the obligation to procure resources to service that demand.[9] Among the various data that must be submitted is hourly system load data, which must be submitted by June 1 of each year for the preceding calendar year. The hourly system load requirement of the Energy Commission parallels this FERC requirement. In fact, the Energy Commission staff frequently acquires medium municipal utility hourly system load data from FERC's website.

B. Energy Information Administration

Staff believes that data report to the Energy Information Administration (EIA) does not duplicate FERC reporting requirement for load research data because EIA only requests monthly loads and not hourly profiles. What we believe to be the relevant reporting requirements can be found in "Instructions for Electronic Reporting of Regional Electricity Supply & Demand Projections," EIA-411. It should also be noted that public data available from EIA as a result of its reporting requirements is aggregated to large geographic areas such as the Western United States. Such aggregation is not useful for analyzing energy consumption patterns within geographic regions of California. Significant differences exist even within California, let alone the much broader aggregations reported by EIA.

C. Western System Coordinating Council

Staff is not aware of Western System Coordinating Council data requirements that either duplicate or supplement the load research data requirements of the Energy Commission.

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9 Phone conversation with Meesha Bond at FERC on October 22, 1998.

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Table 2
UDC Load Profile By Type

UDC	Dynamic Load Profiles Profile Description	Static Load Profiles Profile Description
PG&E	Residential, Non-TOU customers Residential, TOU customers Small Commercial, all building types Medium Commercial, all building types/SICs Medium Commercial, TOU customers **Large Commercial and Industrial** (all SICs) Medium TOU Secondary Med. TOU Primary Voltage Large TOU Secondary Voltage Large TOU Primary Voltage Large TOU Transmission Voltage **Standby Customers** Small (0 to 49 kW) Medium (50 to 199 kW) Medium (200 to 499 kW) Large (500 to 999 kW) Large (=> 1000 kW)	Small Commercial TOU all building types Street Lighting Traffic Controls **Agricultural Load Profiles** Ag Split-Week TOU Ag Short-Peak Ag per hp Ag TOU per hp Ag Large TOU per hp Ag per kW Ag TOU per kW Ag Large TOU per kW
SCE	Residential, all dwellings non-master metered Small Commercial, all building types Medium Commercial/Industrial, all SICs	Residential Master Meter Customers Medium Commercial TOU, all SICs Traffic Controls Street Lighting **Agricultural Load Profiles** Small Ag and Pumping Ag and Pumping Demand Metered Ag and Pumping TOU-PA-5 Ag and Pumping Time Ag-TOU **Large Com and Industrials (all SICs)** Secondary Voltage Level Primary Voltage Level Sub-Transmission Voltage Level
SDG&E	Residential, all customers Small Commercial, all building types Medium Commercial Schedule AD, all SICs Agricultural, all customers Street Lighting **Medium Commercial/Industrial**, all SICs Customer with loads < 500 kW Customer with loads > 500kW Customers on Schedule A6-TOU	NA

VI. Future Options for Obtaining Load Research Data

In this section staff identifies the source and cost of gathering load research data, and provide our opinion as to the best source for the information.

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A. Annual System Hourly Load

Staff believes the best sources of annual system hourly load that will satisfy the Energy Commission's data needs are the utilities. The investor owned utilities, through their UDCs, will be in a position to gather this information. The public utilities, still operating as distinct service areas, will also be in a position to gather this information. Both UDCs and public utilities that have peak demand greater than 200 MW will be required to report this data to FERC via Form 714. Therefore, an Energy Commission's reporting requirement for this same data will cause only trivial incremental costs compared to those of acquiring the data itself. All large- and medium-sized utilities should be required to send the hourly system load data directly to the Energy Commission. Reporting utilities should also be required to send along a definition of their control area. The definition of the load being submitted is important, since for larger utilities it has been common for municipal utilities to be included in the control area.

Staff believes that the FERC reporting requirements are satisfactory as a method of compliance. Utilities are required to submit hourly system load to FERC by June 1st of each year. FERC then post this data to their website. But, the resulting time lag prevents access to the data until well into July. Such a lag is unacceptable in the content of producing annual outlooks. Therefore, staff believes that the utilities should be required to send a copy of their annual system load directly to the Energy Commission at the time they send their Form 714 report to FERC.

Another source of annual system hourly load is the ISO. The ISO cannot, however, provide system data on a comprehensive basis for all of California. It does not have the system load of the utilities that have not chosen to participate. Moreover, as discussed earlier, the Baseline Energy Outlook will examine consumption patterns at more disaggregated levels than ISO data reveals to the public. Thus, aggregate system data provided by the ISO would be less useful compared to regional data provided from the UDCs and public owned utilities within the State.

In the future there may be sizable geographic load served by distributed generation or in some other manner completely disconnected from the present transmission and distribution (T&D) systems of the utilities. Each of these sources will not only have T&D system totals for internal purposes, but many will also be required to report system hourly load to FERC. Therefore, staff believes these market players should be required to report hourly system load and that the cost of providing these data to the Energy Commission will be marginal.

Staff does not know of other sources of system hourly load. Further, when the UDCs and other entities with distribution functions already collect such data, staff believes separate Energy Commission projects such as surveying or metering projects would provide much less accurate data, duplicate existing work, and be extremely expensive.

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As with the current regulations, staff prefers to receive system hourly load data in a common format, such as that developed years ago by EEI. However, staff is prepared to work with data in other formats provided adequate format description is provided.

B. Customer Sector Load Data

As with system load data, staff believes best sources of customer sector hourly load that will satisfy the Energy Commission's data needs are the utilities. The investor owned utilities, through their UDCs, will be in a position to develop this information. Larger public utilities will also be in a position to develop this information. For both the UDCs and public utilities with distribution functions, load research data used for rate design purposes are very similar to data required to satisfy Energy Commission needs. In addition, these same load metering data currently support the UDC calculations of the PX costs/credits and CTCs required by the CPUC.

Staff is unaware of other sources of data that could support customer sector load estimates. As with the system hourly load data, staff believes there would be unnecessary duplication of effort and expense should the Energy Commission conduct separate load metering projects as long as the same data are being gathered elsewhere. The UDCs and larger public utilities have samples in place to collect individual customer hourly load data and to develop estimates of customer sector loads. Therefore, the cost to these utilities of processing existing data for Energy Commission purposes is small. In the past, additional costs were associated with building out samples and running computer programs to aggregate the data into the economically defined customer sectors.

Staff believes all large- and medium-sized utilities (i.e., the three UDCs and the two largest municipal utilities ought to be required to provide customer sector hourly loads to the Energy Commission. In the restructured electricity market, where hourly prices are important signals to market players, the reported customer sector loads should consist of the 8,760 hours of the year to allow for analysis of the impact of hourly prices, load reliability, and costs/benefit analysis of public purpose or other programs. Staff proposes three options for submitting these load data. First, the UDCs and larger municipal utilities could process the data based on Energy Commission needs. Second, UDCs and other utilities could report dynamic load profile data plus ancillary information in lieu of current Energy Commission regulations. Third, the UDCs and other reporting utilities could provide clean data sets of the load sample points, with staff processing the data to fit Energy Commission needs.

Option One: UDCs and Utilities Process Data Into Results

The first option, where UDCs and other reporting utilities process the data, is a status quo option wherein the utilities run software on clean data sets of load sample points to aggregate the data into the economically-defined customer sectors used by the Energy Commission.

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The advantage of this option is that Energy Commission staff receives the resulting load data information in a manner that is readily available to be used in the current versions of our forecasting models.

A potential disadvantage of this option is that it could also impose new processing requirements on the UDCs and other reporting utilities if the Energy Commission needs disaggregated groupings changed. In the new, restructured electricity market, the Energy Commission will be interested in new aggregations of the data for monitoring and other purposes. Given UDC and other utility resource constraints staff believes an arrangement where utilities process the data may not be practical nor will it permit a timely delivery of the desired new profiles. An example of such a problem with UDC processing is the need to use SIC-coded customers counts to prepare weights for the individual samples. Furthermore, this option could add new processing costs to UDC and other reporting utility budgets while providing little benefit to the UDCs given their new role.

Option Two: Accept UDC Static and Dynamic Load Profile Data

The second option has the Energy Commission using the load profiles being posted by the UDCs on their websites supplemented with customer population and sample design information. The advantage to this option is that it places no additional burden on the UDC's load research staff and updated data is continuously available to Energy Commission staff.

The disadvantages, however, are many and great. First, the dynamic load profiles being posted by the UDC's are aggregated by rate class. As indicated in Table 2, these rate classes do not match the sector definitions used by the Energy Commission in forecasting or analysis of building and appliance standards, RD&D, and energy efficiency market transformation programs. Moreover, it would not be useful to convert the forecasting models to rate class models since economic and demographic drivers are related to business sector activity (i.e., SIC Codes). This option also produces a mismatch among the UDC's and public utilities as to the definition of load profile groups. PG&E has twenty-six load profiles, SCE fourteen and SDG&E eight. It is infeasible for the UDCs to change their practice since these rate tariff load profiles are intrinsic to frozen rates mandated by Assembly Bill 1890. The public utilities are not producing dynamic load profiles, nor are they posting for public access static load profiles at this time.

Option Three: UDCs/Utilities Provide Customer Specific Data Energy Commission

The third option, where the Energy Commission receives clean data sets of load sample points and supporting sample documentation, is a substantial change from current Energy Commission regulations. The UDCs and other utilities already develop clean data sets for internal and external reporting purposes. Under this option, the UDCs and other utilities would provide clean data sets along with stratification and population counts needed to weight the data into economically defined customer sectors and other market segments of interest.

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The are several advantages for this option. First, the UDCs and other utilities would be relieved of developing and running programs to aggregate the data into representative customer sectors required by Title 20, California Code of Regulations, Section 1344. Staff believes this option would be less expensive to the UDCs and other reporting utilities and would bring benefits and costs more into line with each other. Second, the sample point data would automatically be classified and treated as confidential under the Energy Commission's new confidentiality regulations. Furthermore, staff would be bound to follow the regulation's aggregation rules that are designed to prevent disclosure of these data. Third, Energy Commission staff would be able to aggregate the data in a manner that would allow more sector specific consumption pattern analysis and forecasting, analysis of building and appliance standards, opportunities for RD&D, and evaluation of energy efficiency market transformation programs.

The disadvantage of this option is the large amount of information that would be passed from the UDC's and other utilities to the Energy Commission. The data would have to be kept on a dedicated server in order to store it efficiently and insure that the confidentiality of the data. This would require upgrades to the Energy Commission's computer hardware and software, as well as additional staff to process and analyze the data for various applications.

C. End-use Load Data

In the past, large utilities conducted air conditioning load metering projects in the residential and commercial building sectors. These projects were expensive to maintain and recruitment into the sample was often difficult, particularly in the commercial building sector. Therefore, after collecting several years' worth of data, some of the utilities ended these projects and/or conducted them in maintenance mode. And, because of resource constraints, recent data have not been analyzed.

Staff believes air conditioning load profiles provide useful information for peak forecasting models as well as for price-response analysis in the new, restructured electricity market. However, at this time, with the rate freeze in effect, it is unlikely that new information will be obtained from further air conditioning load metering projects. Therefore, staff is recommending that new regulations require utilities to conduct air conditioning load metering projects on a periodic basis. Which entities should be responsible for conducting these projects, how the projects should be designed, and when the optimal time might be for the next projects is not clear. Staff believes these questions require further input from knowledgeable parties. In the meantime, utilities and staff should discuss the delivery of the current data that already exists and has been paid for by the ratepayer. If resources continue to be constrained at the utilities, then staff analysis of the primary data may be the most feasible means of obtaining the desired profiles. Having historic, baseline air conditioning load profiles will be valuable for analysis of future markets.

Under existing Energy Commission data regulations large utilities had the flexibility to do many more end-uses other than just air-conditioning. If these programs are completely discontinued in

the future then there will be a loss of a great deal of information about current and future consumption patterns as compared to in the past. Maintaining the flow of this information will be especially important as competitive market generation prices causes energy use patterns to change and the old end-use shapes become less relevant.

D. Large Utility Versus Small Utility Reporting Requirements

There should be different reporting requirements for different types of data. For instant, both large and medium utilities should be required to submit system hourly load data. All utilities that have a peak demand greater than 200 MW and have the responsibility of procuring generation services for that load are currently required to submit system load data to FERC through February 28, 2000.[10] Since most California utilities have means to collect this data, they should be required to report this data to the Energy Commission by June 1 of each year for the previous calendar year. The UDC's and other large utilities that have load metering samples of customer classes in place should be required to submit this data to the Energy Commission. This data will be available into the foreseeable future, since load research samples will be required for transmission and distribution ratemaking purposes.

10 "Directory of Commission External Information Collection Requirements", FERC, March, 1998.

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